UTAH DIVISION OF AIR QUALITY
MODIFIED SOURCE PLAN REVIEW

George W. Cross, President
Intermountain Power Service Corporation
850 West Brush Wellman Road
Delta, Utah 84624

Project fee code: N0327-010

RE: CO PSD Major Modification to DAQE-049-02 at Unit 1 and 2
Intermountain Generating Station
Millard County, Utah CDS-A, ATT, Title V, Title IV, NSPS

REVIEW ENGINEER:	Milka M. Radulovic
DATE:	April 30, 2003
NOTICE OF INTENT SUBMITTED:	November 4, 2002, March 24, 2003, & September 24, 2003
PLANT CONTACT:	Rand Crafts
PHONE NUMBERS:	(435) 864-6494
FAX NUMBER:	(435) 864-0994
SOURCE LOCATION:	850 West Brush Wellman Road Delta, Millard County, Utah
UTM COORDINATES:	4,374.4 km Northing, 364.2 km Easting, Zone 12 datum NAD27

REVIEW:

Peer Engineer ____
John Jenks

DAQ requests that a company/corporation official read the attached draft/proposed Plan Review with Recommended Approval Order Conditions. If this person does not understand or does not agree with the conditions, the PLAN REVIEW ENGINEER should be contacted within five days after receipt of the Plan Review. Special attention needs to be addressed to the Recommended AO Conditions because they will be recommended for the final AO. If this person understands and the company/corporation agrees with the Plan Review or Recommended AO Conditions, this person should sign below and return (can use FAX # 801-536-4099) within 10 days after receipt of the conditions. If the Plan Review Engineer is not contacted within 10 days, the Plan Review Engineer shall assume that the Company/Corporation official agrees with this Plan Review and will process the Plan Review towards final approval. A 30-day public comment period will be required before the Approval Order can be issued.

Thank You

Applicant Contact ____
(Signature & Date)

OPTIONAL: In order for this Source Plan Review and associated Approval Order conditions to be administratively included in your Operating Permit (Application), the Responsible Official as defined in R307-415-3, must sign the statement below and the signature above is not necessary. THIS IS STRICTLY OPTIONAL! If you do not desire this Plan Review to be administratively included in your Operating Permit (Application), only the Applicant Contact signature above is required. Failure to have the Responsible Official sign below will not delay the Approval Order, but will require a separate update to your Operating Permit Application or a request for modification of your Operating Permit, signed by the Responsible Official, in accordance with R307-415-5a through 5e or R307-415-7a through 7i.

"Based on reasonable inquiry, I certify that the information provided for this Approval Order has been true, accurate and complete and request that this Approval Order be administratively amended to the Operating Permit (Application)."

Responsible Official ____________________________________
(Signature & Date)

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TYPE OF IMPACT AREA

Attainment Area	Yes
NSPS	Yes
40 CFR Part 60, Subpart Da (Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After September 18, 1978), and Subpart Y (Coal Preparation Plants)	
NESHAP	No
MACT	No
Hazardous Air Pollutants (HAPs)	Yes (from combustion)
Hazardous Air Pollutants Major Source (No HAPs involved in modification)	Yes
New Major Source	No
Major Modification	No
PSD Permit	Yes
PSD Increment (modeling)	Yes
Operating Permit Program	
Area Source	No
Major	Yes
Send to EPA	Yes
Comment period	30-day

FOR MODIFIED SOURCES

The Notice of Intent is for a modification to an existing source. The following standards are applicable to this review:

NSPS applies to modification?	No
CO PSD review of entire source required?	Yes
NESHAPS applies to modification?	No
HAPs involved in modification?	No
TITLE V required for entire source?	Yes
HAPs MAJOR for modification?	No
NONATT MAJOR for entire source?	No

Abstract

Intermountain Power Service Corporation (IPSC) operates the Intermountain Generating Station (IGS) coal fired steam-electric plant, consisting of two 950 MW units approved in the DAQE-049-02), located near Delta in Millard County. IPSC is requesting a modification to their current approval order (AO) DAQE-049-02 to install combustion and NO_x control system (overfire air) to accommodate the restriction on NO_x emissions imposed by the Acid Rain Program regulations. In addition, IPSC is proposing:

-Replacement-in-kind for the Boilers 1 & 2 low-NO_x burners
-To replace power supplies and motor drives to induced fans
-To clarify and specify where surface-heating area was actually to be added in the Boilers 1 & 2
-Convert minor indoor fugitive emissions to point source outside vented emissions
-Distributed Control System
-Minor changes in the description for clearness

Projected emission changes from this project are from zero to a potential 7,900 ton decrease from the current NO_x PTE with concurrent increase of CO from zero to a potential 9,700 tons. Other pollutants emission rates, stack mass flow, stack temperatures, air contaminant types, and concentrations of air contaminants will remain the same. This project represents a major modification under the Prevention of Significant Deterioration (PSD) program since the proposed physical change can result in the significant emission increase for CO.

Air quality impact analysis of the CO maximum emission increases was performed and it showed that 1 and 8 hours impacts were well below significant impact levels. Furthermore, potential reduction in the target emissions of NO_x is expected to improve visibility and expand available NO_x increments.

Millard County is an attainment area of the National Ambient Air Quality Standards (NAAQS) for all pollutants. New Source Performance Standards (NSPS), Subpart Da and Subpart Y apply to this source. National Emission Standard for Hazardous Air Pollutants (NESHAP) do not apply to this source. However, it is expected in near future NESHAP for new and existing coal and oil-fired electrical utility steam generating units. The proposed NESHAP would implement section 112(d) of the Clean Air Act by requiring certain coal- and oil-fired electric utility steam generating units to meet HAP emissions standards reflecting the application of the maximum achievable control technology (MACT). Boilers 1 & 2 are also Group 1, Phase II units under the Acid Rain Program. IPSC is a PSD major source of NO_x, SO_2, CO, and PM_{10}. Title V of the 1990 Clean Air Act applies to this source. The Title V permit must be modified prior to operation of this modification.

Newspaper Notice

A notice of intent for the following project submitted in accordance with §R307-401-1, Utah Administrative Code (UAC), has been received for consideration by the Executive Secretary, Utah Air Quality Board:

Intermountain Power Service Corporation (IPSC), 850 West Brush Wellman Road, Delta,Utah.
Project Location: 850 West Brush Wellman Road Delta, Millard County, Utah
Project Description: IPSC is requesting a modification to their current approval order (AO) DAQE-049-

02 to install combustion and NO_x control system (overfire air) to accommodate the restriction on NO_x emissions imposed by the Acid Rain Program regulations. In addition, IPSC is proposing:

-Replacement-in-kind for the Boilers 1 & 2 low-NO_x burners
-To replace power supplies and motor drives to induced fans
-To clarify and specify where surface-heating area was actually to be added in the Boilers 1 & 2
-Convert minor indoor fugitive emissions to point source outside vented emissions
-To upgrade the plant distributed controls system
-Minor changes in the description for clearness

The proposed emissions increases (in tons per year) will be as follows: CO 9702.7.

It has been determined that the conditions of the Utah Administrative Code R307-401-6 and the Federal rules have been met. The Executive Secretary intends to issue an Approval Order after a 30-day public comment period is held. This comment period is being held to receive and evaluate public input on the project proposed by Intermountain Power Service Corporation.

I. DESCRIPTION OF PROPOSAL

IGS is a fossil fuel-fired steam-electric generating station that primarily uses coal as fuel for the production of steam to generate electricity. Both bituminous and sub-bituminous coals are utilized. Fuel oil and used oil are also combusted for start-up, flame stabilization and energy recovery.

IGS is a two-unit facility currently approved to operate at a rated capacity of 950 megawatts (MW). Boiler capacity will be rated at 6.9 million pounds per hour of steam flow at 2,822 psi and 1005^{0}F.

IGS has in place bulk handling equipment for the unloading, transfer, storage, preparation, and delivery of solid and liquid fuel to the boilers. No changes of this equipment are required nor expected. No changes in the usage of other raw materials or bulk chemicals are required nor expected.

PROPOSED CHANGES:

Rectified power drives and motors for induced fan motors need to be replaced due to obsolescence. IPSC has approval to increase surface area to the main boilers, and IPSC is now clarifying the location. IPSC is also requesting approval to install over-fire-airports in each boiler to enhance current operating strategies for controlling combustion and NO_x emissions. These changes are needed specifically for reliability, performance and/or routine maintenance needs, will not increase approved plant capacity. IPSC is proposing to upgrade its distributed controls system. In addition, IPSC is performing replacement in kind of Boiler #1 & #2 Low-NO_x burners.

BACKGROUND

On January 11, 2002, the Utah Division of Air Quality (UDAQ) issued to Intermountain Power Service Corporation (IPSC) an approval order (DAQE-049-02) to make certain modifications to the Intermountain Generating Station (IGS). On September 23, 2002, IPSC submitted a Notice of Intent (NOI) to clarify and adjust the scope of those modifications, known as the Dense Pack Uprate Project, as well as receive permitting for other changes. This review is being used to summarize the Dense Pack Project and certain other changes previously approved by UDAQ (DAQE-049-02).

Approval Order DAQE-049-02 allowed IPSC to make certain changes provided IGS operated those changes as a minor modification pursuant to actual to future actual provisions under Utah's Prevention of Significant Deterioration (PSD) rules. Changes allowed under that Approval Order as described in its original NOI included:

Increasing heat input to main boilers
Adding surface area to main boilers
Replacing each unit high pressure turbine with new technology turbines
Replacing one relief valve on each main boiler with one safety valve
Adding wall rings to each scrubber module
Adding helper cooling towers and cooling system enhancements
Enhancements to generators, isophase & motor buses, transformers, boiler feed pumps, high pressure lines, control systems, and other similar changes.

The September 23, 2002 NOI and subsequent requests sought:

To clarify where surface area was actually to be added in main boilers
To replace power supplies and motor drives to induced fans
Replacement-in-kind for low-NO_x burners
To add overfire air ports to main boilers for combustion and NO_x control.
To provide outside venting for slurry tank that currently vent within scrubber buildings.
To upgrade the plant distributed controls system.

Full descriptions of those changes were discussed in IPSC NOI and in subsequent letters, e-mails, and meetings between IPSC and DAQ staff. Additionally, in order to assess how OFA affects both NO_x and CO emissions, an experimental AO was issued on February 14, 2003 to allow installation and testing of an OFA system on Unit 1 to establish relationship between CO and O_2 and NO_x control effectiveness with over-fire air.

PERMIT OPTIONS

Of particular interest for this NOI is how to treat the permitting for over-fire air (OFA). IPSC initially sought to have OFA permitting as a minor modification under certain PSD provisions. However, the testing of the OFA system is complete, the results showed that CO might increase in major net significant amounts (greater than 100 tons per year) when NO_x is controlled to low emission rates.

For the dense pack modifications, IPSC chose to modify combustion for NO_x control during increased heat input, rather than utilize technological add-on controls. Combustion in the boiler was fine-tuned to optimize performance against NO_x emissions using such methods as burner-out-of-service, excess oxygen control, fuel management, and other boiler operational changes.

Although such practices have been successful, IPSC believes that replacing this combustion methodology with technical add-on controls would better optimize boiler performance and control of NO_x emissions.

The use of OFA will allow IPSC to control NO_x without a significant net increase due to the dense pack modifications. However, IPSC believes it is possible that certain OFA configurations can cause a net significant increase in CO emissions. Therefore, IPSC seeks permitting of OFA as a major modification for CO under PSD.

PRODUCTION SUMMARY:

IPSC operate two power generating units, each 950 MWhe, with steam flow of 6.9 million pounds per hour, heat input of 9,225 million Btu per hour, requiring the use of 5.6 million tons of coal each year. See AO #DAQE-049-02 and it's corresponding NOI for details. Nothing with IPSC current NOI is intended to change those production aspects of the previously approved uprate project.

EMISSION CHARACTERISTICS:

During the boiler normal combustion with about 3% O_2 in the flue gases with currently typical coal, IPP is able to operate under their NO_x emissions limit of 0.461 lb/MMBtu and CO level of 1989.6 tons per year. As coal reserve change, it is anticipated that operating in the same fashion would cause NO_x emissions potential value to raise and potentially exceed NO_x emissions limit. The solution is introducing the OFA system, which actually reduces excess O_2 and NO_x emissions and thus allows use of variety of coals without exceeding the NO_x emissions limit. Along with this NO_x control, it will be a potential commensurate increase in CO emissions up to 180 ppm resulting in plat potential to emit (PTE) CO emissions of 11,694.3 tons per year which leads to six fold increase.

The composition and physical characteristics of emissions resulting from the proposed modifications are not expected to change with the exception of carbon monoxide (CO), which may increase by a net significant amount. Other pollutant emission rates, chimney mass flow, temperature, air contaminant types, and concentration of air contaminants will remain the same as proposed in the uprate project. The current pollution control devices (PCD) include low-NO_x burners, fabric filters and wet scrubbers. No increases in PTE for any pollutant except for CO will occur as a result of PCD.

Specifically, it is possible for CO emissions to increase as over-fire air (OFA) is used to decrease NO_x emissions. When NO_x emissions are fully minimized utilizing OFA, IPP expected that CO emissions could increase from 1989.6 tons per year (as calculated by AP-42- EPA's compilations of emission factors, and verified with testing) to 11,692.3 tons per year (as projected by boiler testing).

The following 30-day average emission rate parameters are provided as required:

Parameter	Current Before PCD	Expected After PCD	Potential change after modification
Particulates	96,000 lbs/hr	50 lbs/hr	none
Nitrogen Oxides	0.42 lbs/MMBtu*	0.40 lbs/MMBtu	0.37 lbs/MMBtu minimum
Sulfur Dioxide	1.8 lbs/MMBtu	0.06 lbs/MMBtu	none
Carbon Monoxide	0.022 lbs/MMBtu**	0.040 lbs/MMBtu	***0.143 lbs/MMBtu maximum
Temperature	325 F	120 F	none
Stack Gas Volume	130,000,000 scfh	130,000,000 scfh	none
VOC	1.71 lb/hr	1.71 lb/hr	immeasurable
Hydrochloric Acid	0.67 lbs/hr	0.02 lbs/hr	none
Hydrofluoric Acid	0.14 lbs/hr	0.004 lbs/hr	none
Antimony	0.007 lbs/hr	0.000008 lbs/hr	none
Arsenic	0.03 lbs/hr	0.00006 lbs/hr	none
Beryllium	0.0009 lbs/hr	0.0000005 lbs/hr	none
Cadmium	0.001 lbs/hr	0.00001 lbs/hr	none
Chromium	0.06 lbs/hr	0.0001 lbs/hr	none
Cobalt	0.006 lbs/hr	0.00001 lbs/hr	none
Lead	0.013 lbs/hr	0.00003 lbs/hr	none
Manganese	0.016 lbs/hr	0.00005 lbs/hr	none
Mercury	0.0001 lbs/hr	0.00001 lbs/hr	none
Nickel	0.009 lbs/hr	0.00005 lbs/hr	none
Selenium	0.005 lbs/hr	0.00065 lbs/hr	none

NOTES:
*NO_x emissions are estimated AFTER low NO_x combustion.
**Current CO emissions based upon AP-42 factors and testing with OFA;
***modified CO emissions based upon testing.

Carbon monoxide (CO) emission rates are provided based upon two different derivations. The current CO rate of 0.022 lbs/MMBtu is based upon AP-42 calculations (this value was also shown to be the same in the testing performed before the PCD). The projected CO rate is based upon testing of overfire air. The increase from a current calculated rate to a projected rate is about 9,700 tons for the plant NO_x emissions can concurrently decrease up to 7,900 tons from plant PTE.

Pollution Control Device Description:

Present pollution control device equipment for combustion for the Unit 1 and 2 boilers includes dual-register low NO_x burners, baghouse type fabric filters for particulate removal, and flue gas desulfurization scrubbers. Control equipment for the handling and transfer of solid material include dust collection filters.

Pollution Control Device Upgrade:

The project includes the addition of overfire air (OFA) ports and replacement or repair of dual register low NO_x burners.

Description of the Overfire Air (OFA) System and Control Devices.

Overfire air is needed, in part, to accommodate the restriction on NO_x emissions imposed by Acid Rain regulations that were promulgated based upon the Clean Air Act Amendments of 1990. Specifically, in 2007. Acid Rain requirements impose a 0.46 lb/MMBtu annual cap for NO_x emissions on IPP. Since an early election was filed for IPP, this new limit was delayed. Current forecasts of coal quality indicate that without OFA, the new Acid Rain limit could be difficult to attain. A multiport overfire air system will be added to ensure stable operation in accordance with specified emissions limits. The OFA system will redirect approximately 10-15 percent of total combustion air to a staged system of ports located directly above the top row of burners.

The OFA system at the Intermountain Generating Station (IGS) is being provided by Babcock Power, Inc. (BPI). It consists of one row of OFA ports located on the elevation immediately above the top burner levels on both the front (south) and rear (north) sides of the boiler. Each row consists of eight, identical, OFA ports with one port located over each of the six burner columns (column ports) and one port located on each end of the OFA rows near the side walls of the boiler (wing ports).

Air to the OFA system is provided by the Secondary Air (SA) system. A feeder duct extends from each SA header duct to the corresponding OFA header through which secondary air is admitted to the OFA headers. Each OFA feeder duct includes isolation dampers operated by Jordan rotary electrical drives.

OFA airflow to the boiler is admitted and controlled through the OFA port dampers. Each OFA port is partitioned into separate 1/3 and 2/3 sections. Airflow, through each set of OFA ports, is controlled by port dampers located in each partition. The four, 1/3 port dampers for an OFA row half are connected or ganged together for simultaneous operation by a Jordan rotary electrical drive. The same configuration is implemented for the 2/3 port damper sets. This creates a total of four, 1/3 port dampers/drives and four, 2/3 port dampers/drives for over-air flow control to the boiler.

Control and monitoring of all OFA damper drives is done by the IGS combustion control system. Additionally, an array of three Air Monitor Corporation VOLU-probes and thermocouples measures OFA mass flow through each of the four feeder ducts. Control signals operate all port dampers simultaneously; independent damper control is not available.

Control Strategy Description

More detailed information is in the documentation provided by Babcock Power Interface included in the" Report on Good Combustion Practices".

OFA is most effective controlling NO_x formation at unit loads above 60% of the rated load of 950 MW. When utilized at the 60% load point and above, OFA flow will be accomplished by the combination of opening OFA feeder and port dampers and decreasing the combustion air damper positions, so as to maintain target total SA flow based on unit load.

The OFA port and feeder duct damper groups have modulating capability and can be operated either fully open, fully closed, or throttled to positions in-between. (Open position can be biased to achieve balanced O_2 distribution across the burner front). SA airflow to the OFA system is attained by simultaneously decreasing the openings of all the combustion air dampers feeding each of the burner elevations that are in operation. This decrease is superimposed on the existing automatic control biasing of each elevation combustion air in accordance with pulverizer loading.

This SA damper control is additive to the existing bias required to change burner airflow in proportion to the individual pulverizer load. The action of the sum of both biases will result in less secondary air directly to the burners, as OFA is being introduced, but the relative secondary air distribution between burner elevations will remain unchanged.

The OFA port relative open area sizes, 1/3 and 2/3, are calculated to provide the correct velocity of the OFA to attain the proper penetration of the OFA into the combustion region of the furnace above the burners. All ports of a given kind, 1/3 or 2/3, will open or close following a program designed to open the correct area to roughly produce the proper penetration velocity as the OFA air flow rate changes with boiler load. OFA operation will include the following configurations:

All 1/3 and 2/3 ports closed
1/3 ports open, 2/3 ports closed
1/3 ports closed, 2/3 ports throttled
1/3 ports closed, 2/3 ports open

Target Operating Parameters for OFA Design

The OFA modifications shall provide for a continuous boiler rating of 6,900,000-lbs/hr output at 1005°F superheat and 1005°F reheat temperature under normal operating conditions. These modifications shall include the design, fabrication and installation on both IGS Units 1 & 2 for an overfire air system capable of providing a reduction in NO_x emissions of 15% and consistent NO_x emissions of less than 0.40 lbs/MMBtu under all operating modes.

Of particular interest to IPSC were the performance parameters associated with operation at 950 Megawatts gross generation (6.75 MMlbs/hr steam flow). These include:

a. Total NO_x output of 0.40 lbs/MMBtu or less up to an overall reduction of 15%. Current maximum average of 0.461 lbs/MMBtu.

b. Superheat and reheat temperatures as well as NO_x emissions must remain within acceptable ranges.

b. Minimal impact on average unburned carbon (LOIs) and carbon monoxide (CO) concentrations within the boiler.

NOTE: These are target parameters only for purposes of OFA design and performance evaluation, and in no way IPSC intended to limit boiler operation in any way.

EMISSION POINT:

The present emission point for the IGS boilers is a lined chimney that discharges at 712 feet above ground level (5,386 feet above sea level). The chimney location is 39° 39' 39" longitude, 112° 34' 46" latitude.

SAMPLING/MONITORING:

Emissions from boiler combustion are continuously sampled and monitored at the chimney for nitrogen oxides, sulfur oxides, carbon dioxide, and volumetric flow. Opacity is measured at the fabric filter outlet. Other parameters recorded include heat input and production level (megawatt load). Monitoring will remain unchanged. Other emissions not directly monitored are calculated using engineering judgments, emission factors, and fuel analyses.

OPERATING SCHEDULE:

Operation at IGS is 24 hours per day, seven days per week.

MODIFICATION SPECIFICATIONS and CONSTRUCTION SCHEDULE:

a. Induced Fan Drive Power Supply Obsolescence & Replacement

There are four induced draft (ID) fans for each generator at the Intermountain Generating Station. The fans are centrifugal airfoil, double width, double inlet design driven by synchronous motors through variable frequency drives. The flow modeling has shown the best approach to correcting our obsolescence problem may be to replace our current power drives with new induced pulse width modulation technology. Such a change would require motor replacements. The existing variable frequency drives are of 1980 vintage, no longer manufactured, require increasing maintenance, certain critical repair parts are no longer available, and frequently fail, although such failures do not currently impact station operation due to fan redundancy. The variable frequency drives are scheduled for replacement beginning in 2004. Replacement of the variable frequency drive systems will not include modifications of the existing fans and no change beyond approved capacity would result from the possible drive and motor horsepower change out. We are therefore requesting approval accordingly.

b. Changes to Approved Boiler Modifications

Previously approved but uncompleted boiler modifications included the addition of preheat steam tubes to the convective pass of each boiler. Due to latest modeling and operational data, this NOI proposes to change those modifications to the radiant section of the boiler, which will include the addition of platen superheater surface. The 36-platen superheater pendants, in each boiler, are scheduled to be lengthened by approximately 8 feet from their present approximate 40-foot length. The purpose of these changes was for better combustion control. These proposed changes are still on track for Unit 1 and Unit 2 in March 2004, meeting the construction schedule originally set forth under DAQE-049-02.

c. Low NO_x Burner Maintenance & Replacement

IPSC proposes to replace the existing burners as needed in future years. Burners have not met their design life and need to be replaced or rebuilt. The replacement or rebuild of the present low NO_x burners is proposed as replacement-in-kind, as IPSC does not propose to increase heat input through the new burners from what currently exist.

The current burners have already been shown in different tests to accommodate heat input rates of the current uprate modification (9,225 MMBtu/hr). Tests in April of 2002, demonstrated maximum heat input per existing burner (B&W with 58" throat) to be 248 MMBbtu per hour. New low NO_x burners (Advanced Burner Technologies, Opti-Flow with 51" throat and will be limited with maximum heat input per burner at up to 248 MMBtu per hour at the same NO_x control levels to qualify as replacement-in-kind. Additionally, the maximum burner heat input level is limited with existing mills (B&W ModelMPS89). Burner maintenance and repair for Unit 1and burner replacement for Unit 2 will begin in 2004 and continue through 2008 in a multi-staged process.

d. OFA Ports

A multiport OFA system will be added to ensure stable operation in accordance with specified emissions limits. IPSC currently uses a combustion tuning methodology for NO_x control that they find is costly and somewhat haphazard. OFA air is also needed, in part, to accommodate the restriction on NO_x emissions imposed by Acid Rain regulations that were promulgated based upon the Clean Air Act Amendments of 1990. Specifically, in 2007 Acid Rain requirements impose a 0.46 lb/MMBtu annual cap for NO_x emissions on IPP. Since an early election was filed for IPP, this new limit was delayed. Current forecasts of coal quality indicate that without OFA, the new Acid Rain limit could be difficult to attain.

The OFA system will redirect approximately 10 to 15 percent of total combustion air to a staged system of ports located directly above the top row of burners. When OFA is utilized to minimize NO_x emissions as much as possible, CO emissions may increase by a net significant amount.

A full description of the OFA system and its operation has already been filed. In fact, IPSC has installed and tested an OFA system on Unit One as allowed by an experimental approval order.

The results of the test confirmed potential CO increases with OFA system.

e Distributed Control System

IPSC had proposed replacement and upgrade of the distributed control system at IGS in the April 2001 NOI. However, AO #DAQE-049-02 did not specifically identify the DCS replacement, except for the description in the AO abstract as "other similar changes." For clarity, IPSC wishes to have the DAQ specifically identify the DCS project in the AO, and treat this NOI as such request. Certain control systems will be upgraded as an integral part of the uprate modification (i.e., new turbine, boiler modifications, OFA system) and are considered part of those modifications. However, IPSC is proposing to upgrade all corresponding operating control systems as well. The Intermountain Generating Station is controlled by several subordinate systems. These systems include a coordinated control system, a burner management system, a combustion control system, a turbine electro-hydraulic control system, a turbine supervisory system as well as several plant data acquisition and status display systems. Components within these systems are becoming increasingly hard to obtain from either primary or secondary manufacturers. Although there have been no system failures that have causes forced outages, these control systems are now causing reliability concerns due to the unavailability of key hardware.

The existing control systems are scheduled to be replaced beginning in the 2004 spring outage. The various control systems will be replaced with a centralized, distributed control system in a phased approach over a several year period to reduce the impact on generation capability. The current schedule shows this project being completed in the spring of 2007.

f. New Point Source Venting

IPSC is proposing to vent minor indoor source fugitive emissions to vented point source emissions.

There are six tanks in each the two scrubber buildings. Four are in operation at any given time for each unit to control sulfur and acid gas emissions. A diagram indicating proposed venting, and a worksheet indicating worst-case emissions was submitted as part of the NOI. We do not believe that particulates are a significant part of venting, but we have included those calculations based upon evaporation rates. Emissions are characterized worst case as follows:

Estimated Vent Flow Rate	2500cfm
Emission Temperature	51° C
Vent Particulate Emission Rate	0.11 tons/yr
Number of Operating Vents	8 (out of 12)
Total Emission Rate (PM_{10})	0.88 tons/yr
Stack Vent Elevation	4825 ft (149 ft above ground level)

Applicability Determinations

OFA

The installation of OFA to the Units One & Two boilers can be expected to cause a decrease in NO_x with a concomitant increase in CO. This follows a sliding relationship; i.e., if NO_x levels are maintained, no CO increase can result. If NO_x is minimized to the greatest extent possible, CO may rise accordingly. IPSC predicts that normal operation will show a slight decrease in NO_x with the use of overfire air, resulting in a small increase in CO.

IPSC in its NOI did not propose any requirement that IPSC must operate the OFA and Low-NO_x burners to fully minimize NO_x. IPSC's intent in adding further NO_x controls is to balance combustion performance with environmental control. IPP intends to continue to operate in such a manner that maximizes performance, yet still meets environmental limits as mandated by regulation and permit. This means that NO_x will be controlled to meet short-term thirty-day rolling average limits, as well as the annual WEPCO requirements outlined in the AO.

New Source Performance Standards.

IGS operates as a New Source Performance Standard (NSPS) power plant, regulated under Title 40 of the Code of Federal Regulations, Part 60, Subpart Da. The proposed changes do not trigger NSPS applicability. "Modification" is defined at 40 CFR 60.14 to include any change in operation of a source that increases the maximum hourly emissions of a Part 60 regulated pollutant above the maximum achievable during the previous five years. (See 40 CFR 60.14(h)). Even though the use of OFA to enhance combustion and reduce NO_x can increase carbon monoxide (CO), CO is not a regulated pollutant under NSPS Subpart Da, which is applicable to IGS.

Prevention of Significant Deterioration.

IGS was constructed under Prevention of Significant Deterioration (PSD) permits, and with the exception of possible CO increases, none of the changes proposed are a major modification for PSD purposes. Based upon boiler combustion performance modeling and tests, CO emissions are expected to increase by a net significant amount (greater than 100 tons per year). Those projected CO increases have been modeled for possible air impacts and have been shown they do not cause or contribute to a violation of a NAAQS, PSD increment, or adverse Class I impact. Those modeling results have already been submitted to UDAQ.

Modeling

CO modeling was performed for the total potential emission of CO to evaluate if increases do not cause or contribute to a violation of a NAAQS, PSD increment, or adverse Class I impact. For the worst case 1 hour CO short term emission rate of 11,439 lbs/hr, ISC modeling shows results of 941.5 ug/m3 . For the 8 hour CO short term emission rate of 5,719.5 lbs/hr, ISC modeling shows impact results of 119.8 ug/m3. This is well below the modeling significant levels of 2000 and 500 ug/m3, respectively, confirming no adverse contribution or violation.

Title V Permit

IGS operates under a Title V permit (#2700010001). IPSC intends to continue to operate in full compliance with that permit and applicable requirements. -

The changes proposed herein will affect only one condition of the current Title V permit. Condition II.B.1.i limits CO emissions on an annual basis. Since maximizing NO_x control efficiency can cause CO emissions to exceed this limit, IPSC requests that this condition be revised accordingly.

II. EMISSION SUMMARY

The emissions from Intermountain Generating Station will be as follows:

Pollutant	Current Emissions tons/year	Emission Increases tons/year	Total Emissions tons/year
PM_{10}	3,286.7	0.00	3,286.7
SO_2	11,332.3	0.00	11,332.3
NO_x	37,868.2	0.00	37,868.2
CO	1989.6	9702.7	11,692.3
VOC	63.91	0.00	0.00
HAPs			
Lead	0.39168	0.00	0.39168
Berillium	0.00892	0.00	0.00892
Fluorides (HF)	16.8	0.00	16.8
Sulfuric Acid	8.8	0.00	8.8
Mercury	0.00	0.00	0.00
Total HAPs	0.00	0.00	82.67
Other NON-VOC HAPs	93.2	0.00	93.2

III. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Good Combustion Practice

Since fuel utilization and combustion efficiency suffer in attempts to minimize NO_x generation in the boiler, CO can rise due to incomplete or poor combustion. There are no add-on controls specific to CO technologically, nor are they commercially available in any form for utility steam generators. As a matter of practice, BACT for CO is considered to be Good Combustion Practice.
Good combustion practice (GCP) is defined as system design, operation, and maintenance techniques, which can increase combustion efficiency. The GCP control strategy includes collectively applying a number of combustion conditions to achieve three broad goals:

(1) Maximize fuel utilization and boiler efficiency;
(2) Minimize byproducts of poor combustion (CO) and
(3) Minimize creation of combustion related pollutants (NO_x).

The emphasis in an effective good combustion practice lies in the design of the combustion system. There are several specific measurable parameters that compose a set of combustion indicators that can be related directly or indirectly to the design of the GCP components. These combustion parameters are:
-CO levels in the flue gas;
-Loss of Ignition of carbon in the ash;
-NO_x levels in the flue gas
-Excess O_2 in the combustion air; and
-Heat Rate (i.e., plant efficiency - heat input vs. load production).

Good combustion is essentially a balance of the GCP components, which by the nature of the combustion process are antagonistic. High fuel utilization and boiler performance increases NOx creation. Minimizing NO_x through combustion controls increases CO and LOI, and decreases efficiency. GCP design balances these effects to optimize each component. CO is a good indicator of combustion efficiency, which when measured before and after modifications to a combustion process, can verify GCP design.

The ability to maintain low CO and NO_x concentrations in flue gases is dependent on combustion design features such as those found in retrofit OFA ports. Once the design has been demonstrated to be GCP, GCP is further employed in operating and maintenance practices. Since CO is minimized as an inherent component to maximizing efficiency and lowering operating costs, there exists a natural incentive towards GCP in OFA operation and maintenance. Since OFA has been tested and emissions of CO can be correlated to other operating parameters, GCP therefore can be demonstrated through the application of those correlation curves to actual operation.

- **Best Available Control Technology (BACT).**

IGS was constructed under a PSD permit which required BACT. Since the CO emissions increases may trigger a major PSD modification, a Top Down CO BACT analysis was performed.

Top-Down BACT Process

EPA has developed a process for conducting BACT analyses. This method is referred to as the "top-down" method. The steps are:
Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

Each of these steps has been conducted for CO and is described below.

Potential control technologies for CO were identified from a number of sources including the EPA RBLC database, control technology vendors, technical journals and web sites, and other